Jennifer Brooks Hutchinson
Senior Counsel

April 13, 2016

VIA HAND DELIVERY & ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket 4599 – 2016 Retail Rate Filing
Docket 4556 – 2016 Renewable Energy Standard (RES) Charge and Reconciliation
Responses to Record Requests

Dear Ms. Massaro:

Enclosed are ten (10) copies of National Grid's[1] responses to the record requests issued by the Rhode Island Public Utilities Commission at the evidentiary hearing on March 28, 2016 in the above-referenced dockets.

Thank you for your attention to this transmittal. If you have any questions, please contact me at 401-784-7288.

Very truly yours,

Jennifer Brooks Hutchinson

Enclosures

cc: Docket 4599 Service List
Docket 4556 Service List
Steve Scialabba, Division
Leo Wold, Esq.

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).

280 Melrose Street, Providence, RI 02907
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Certificate of Service

I hereby certify that a copy of the cover letter and any materials accompanying this certificate was electronically transmitted to the individuals listed below.

The bound versions of this filing were hand delivered to the Rhode Island Public Utilities Commission and to the Rhode Island Division of Public Utilities and Carriers on February 15, 2016.

___________________________________ April 13, 2016

Joanne M. Scanlon Date

National Grid – 2016 Annual Retail Rate Filing - Docket No. 4599
Service List Updated 3/18/16

Name/Address	**E-mail Distribution**	**Phone**
Jennifer Brooks Hutchinson, Esq. National Grid. 280 Melrose St. Providence, RI 02907	Jennifer.hutchinson@nationalgrid.com; Celia.obrien@nationalgrid.com; Joanne.scanlon@nationalgrid.com; Adam.crary@nationalgrid.com; Tiffany.forsyth@nationalgrid.com;	401-784-7667
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Certificate of Service

I hereby certify that a copy of the cover letter and any materials accompanying this certificate was electronically transmitted to the individuals listed below.

The paper copies of this filing are being hand delivered to the Rhode Island Public Utilities Commission and to the Rhode Island Division of Public Utilities and Carriers.

__________________________________ April 13, 2016

Joanne M. Scanlon Date

Docket No. 4556 - National Grid – 2016 Standard Offer Service (SOS) and Renewable Energy Standard (RES) Procurement Plans
Service List updated 3/18/16

Name/Address	E-mail Distribution	Phone
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Office of Energy Resources Nicholas Ucci Christopher Kearns	Nicholas.ucci@energy.ri.gov; Christopher.Kearns@energy.ri.gov; Danny.Musher@energy.ri.gov;	

Record Request No. 1

Request:

Given the fact that all payments go to electric first and then are allocated to gas, is there any delay in posting to customer accounts? Is the allocation to gas from electric a manual or automated function? Does any delay in the posting of receivables from electric to gas affect the accounts receivable aging reports provided to the PUC?

Response:

Rhode Island customer bills are currently separated between gas and electric. A customer taking both services receives two bills each month, and remits payment on each separately. Those payments are posted against their designated gas and electric bills as received, thus there is no delay. Each of these bills is assigned to the electric company within the customer service system which is why the gas information must be re-assigned through an automated function. This does not generate a delay in posting of cash to the customer's account and thus there is no impact on A/R aging reports provided to the PUC.

Record Request No. 2

Request:

Please provide the relevant tariff pages discussing the calculation of cash working capital for each gas and electric tariff.

Response:

Please see Attachment RR-2, which contains the pages relevant to the calculation of cash working capital pages in both gas and electric tariffs.

In Docket No. 4065, (General Rate Case), the Commission approved the Company's proposal for full reconciliation of cash working capital associated with Standard Offer Service (SOS). The first annual calculation of SOS cash working capital was proposed in the 2011 Annual Retail Rate Filing (Docket No. 4226), and was approved in Order No. 40504. Therefore, while the calculation of cash working capital is not specifically outlined in the Standard Offer Adjustment Provision tariff (RIPUC 2157), full reconciliation of this cost means that annually, the Company will calculate the SOS cash working capital impact, and reconcile it against the cost. The Company has performed this analysis and reconciliation in each Annual Retail Rate filing since the 2011 Annual Retail Rate Filing.

GAS COST RECOVERY CLAUSE

WC_{FC} Working Capital requirements associated with Supply Fixed Costs. See Item 5.0 for calculation.

4.0 INVENTORY FINANCING:

IFs = $(ASB_U + ASB_L) * COC$

Where:

IF_S Inventory Finance Charges for storage

ASB_U Average underground storage balance

ASB_L Average LNG storage balance

COC Weighted Pre-tax Cost of Capital, consisting of three components: Short-term Debt, Long-term Debt, and Common Equity. The Common Equity components shall reflect the rates approved in the most recent rate case proceeding. The Short-term debt component shall be based on the Company's actual short-term borrowing rate for the twelve months ended March as presented in the Company's annual Distribution Adjustment Clause Filing.

5.0 WORKING CAPITAL REQUIREMENT:

$WC_M = WCA_M * [DL / 365] * COC$

Where:

WC_M Working Capital requirements of Supply Fixed (WC_{FC}) and, Storage Fixed (WC_{SFC}), Supply Variable (WC_{SV}), Storage Variable Product (WC_{SVC}) or Storage Variable Non-product (WC_{SVNC}) Cost Components.

WCA_M Working Capital Allowed in the Supply Fixed, Storage Fixed, and Supply Variable, Storage Variable Product, or Storage Variable Non-product Cost component calculations.

DL Days Lag approved in the most recent rate case proceeding.

COC Weighted Pre-tax Cost of Capital, consisting of three components: Short-term Debt, Long-term Debt, and Common Equity. The Common Equity components shall reflect the rates approved in the most recent rate case

GAS COST RECOVERY CLAUSE

proceeding. The Short-term debt component shall be based on the Company's actual short-term borrowing rate for the twelve months ended March as presented in the Company's annual Distribution Adjustment Clause (DAC) filing in support of the Earnings Sharing Mechanism (ESM). The long-term debt component will be based on the Company's actual long-term borrowing rate as presented in the Company's annual DAC filing.

6.0 DEFERRED GAS COST ACCOUNTS:

The Company shall maintain two (2) separate Deferred Gas Cost Accounts: (1) Fixed Costs and revenues and (2) Supply Variable Costs and revenues. Entries shall be made to each of these accounts at the end of each month as follows:

An amount equal to the allowable costs incurred less:

1. Gas Revenues collected adjusted for the RIGET and uncollectible percentage approved in the most recent rate case proceeding;

2. Credits to costs, including but not limited to GCR Deferred Responsibility surcharge/credits and Transitional Sales Service (TSS) surcharge revenues,

   and including

3. Monthly interest based on a monthly rate of the current Bank of America prime interest rate less 200 basis points (2%), multiplied by the arithmetic average of the account's beginning-of-the-month balance and the balance after entries 1. and 2. above.

7.0 REFUNDS:

Any refund associated with the Company's total gas cost for Sales customers shall be credited to the Deferred Cost Account.

8.0 WEIGHTED AVERAGE UPSTREAM PIPELINE TRANSPORTATION COST:

At the request of a marketer or the Division, the Company will provide within 21 days an estimate of the pipeline path costs for the next GCR year beginning November 1. The estimate will be based on the most recent GCR filing updated for current commodity pricing and other known changes which would significantly affect the factor. Concurrent with the annual GCR filing, the Company shall calculate the final weighted average cost of upstream pipeline transportation capacity. The cost shall be applicable to capacity release under the

THE NARRAGANSETT ELECTRIC COMPANY
STANDARD OFFER ADJUSTMENT PROVISION

calendar year and make a filing with the Commission. The Company will propose at that time a methodology to recover or credit the balance, as appropriate, over the subsequent twelve month period or as otherwise determined by the Commission. The Commission may order the Company to recover or credit the balance over any reasonable time period from (i) all customers, (ii) only Standard Offer Service customers, or (iii) through any other reasonable method.

In the Standard Offer Administrative Cost Reconciliation, the Company shall reconcile its administrative cost of providing Standard Offer Service with its Standard Offer Service revenue associated with the recovery of administrative costs, and the excess or deficiency, including interest at the interest rate paid on customer deposits, shall be credited to, or recovered from, Standard Offer Service Customers in the subsequent year's Standard Offer Service Administrative Cost Factor. The Company may file to change the Standard Offer Service Administrative Cost Factor at any time should significant over- or under- recoveries of Standard Offer Service administrative costs occur.

For purposes of calculating the Standard Offer Service Administrative Cost Factors, which is applicable to customers receiving Standard Offer Service, administrative costs associated with arranging Standard Offer Service pursuant to this provision shall include:

1. the cost of working capital;
2. the administrative costs of complying with the requirements of Renewable Energy Standard established in R.I.G.L. Section 39-26-1, the costs of creating the environmental disclosure label, and the costs associated with NEPOOL's Generation Information System attributable to Standard Offer Service;
3. the costs associated with the procurement of Standard Offer Service including requests for bids, contract negotiation, and execution and contract administration;
4. the costs associated with notifying Standard Offer Service customers of the rates for Standard Offer Service and the costs associated with updating rate change in the Company's billing system; and
5. an allowance for Standard Offer Service- related uncollectible accounts receivables associated with amounts billed through Standard Offer Service rates, the Renewable Energy Standard charge and the Standard Offer Service Administrative Cost Factors at the rate approved by the Commission.

The allowance for Standard Offer-related uncollectible amounts shall be estimated for purposes of setting the Standard Offer Service Administrative Cost Factors for the upcoming year as the approved rate applied to the sum of (1) an estimate of Standard Offer costs associated with each customer group pursuant to the Standard Offer and Renewable Energy Standard procurement plans in effect at the time, as approved by the Commission, and (2) any over- or under-recoveries of Standard Offer Service from the prior year associated with each customer group. This amount shall be subject to reconciliation only for actual Standard Offer Service revenue billed by the Company over the applicable period.

Record Request No. 3

Request:

Please provide the amount of the double recovery for each of the years since Docket 4323 was decided and the pension tracker was first used. Please also provide the cumulative amount.

Response:

The total Pension/PBOP expenses that were included in the recovery of Standard Offer Service Administrative Costs since the Pension/PBOP Adjustment Factor took effect in February 2013 are as follows:

Annual Retail Rate Filing Year	Period During Which Costs Were Incurred	Total Pension/PBOP Expenses Included in Filing
2014	February 2013 to December 2013	$51,826
2015	January 2014 to December 2014	$39,503
Cumulative Total		$91,329

The Company will refund the cumulative amount, plus interest, in its next Pension Adjustment Factor filing.

Prepared by or under the supervision of: Adam S. Crary and William R. Richer

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Record Request No. 4

Request:

Why is the first step of the development of transmission rates based on the coincident peak demand? Why are distribution charges based on non-coincident peak if transmission seems to be based on the rate class' coincident peak demand?

Response:

Pursuant to the Company's[1] Transmission Cost Adjustment Provision, RIPUC No. 2115, the Transmission Service Cost Adjustment recovers from customers transmission costs billed to the Company by entities such as New England Power Company (NEP), by any other transmission provider, and by regional transmission entities such as the New England Power Pool, a regional transmission group, an independent system operator or any other entity that is authorized to bill Narragansett directly for transmission services. Transmission costs are incurred by retail electric companies, including Narragansett, based on each company's demand at the time of each month's transmission system peak, measured and billed monthly (i.e., 12-Coincident Peak, or 12-CP). This methodology appropriately recognizes that transmission facilities are sized and built to accommodate the maximum aggregate demand on the system. Thus, since transmission costs are allocated to the Company based on coincident peak, it is appropriate to allocate these costs to rate classes based on contribution to coincident peak. In its Order dated April 14, 2010, Order No. 19965, in Docket No. 4065 (the Order), the PUC found that allocating transmission costs based on the coincident peak is reasonable and that the allocation of this cost be calculated annually as part of the Company's annual retail rate filing.[2]

Distribution system facilities consist primarily of individual feeders and substations. The cost of these facilities is based upon the forecasted peak demand on each facility, which does not necessarily occur at the same point in time. A non-coincident peak allocator, based upon class maximum demands, is typically chosen to allocate the costs associated with the distribution system because this allocator specifically recognizes that customer peaks do not occur at the same point in time.

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[1] The Narragansett Electric Company d/b/a National Grid (Narragansett or the Company).
[2] See Order No. 19965, Docket No. 4065, at 17, 26.

Record Request No. 5

Request:

How are the total renewable generation credits, ISO-NE sales, and QF purchases measured? Are they based on actual meter reads (at which point) and if not, how? Please explain what each of the columns in ASC-16, page 1 represent (please define the headers).

Response:

New England Power Company, as the Host Participant and Assigned Meter Reader, complies with filed Tariffs and ISO-NE Operating Procedures and utilizes the best data available for settlement.

QF customers have an interval retail meter (a meter that can measure hourly usage) at the customer's delivery point that uses one channel in the meter for on-site usage that is billed to the QF. This channel measures hourly usage that is summed for the billing period. The meter uses another channel to measure the generation exported to a generator asset at ISO-NE. For projects less than 5 MWs, the Company is the owner of the generation asset. Payments to the QFs and sales to ISO-NE are based on actual meter reads.

Net Metered customers with Eligible Net Metering Systems in excess of 25 kW also must have an interval retail meter at the customer's delivery point. One channel in the meter measures the customer's hourly usage and another channel measures hourly generation exported to a generator asset at ISO-NE. These two values are then 'netted' (total monthly generation is subtracted from monthly use) over the billing period. A Net Metered customer is billed if there is more on-site usage than generation, or it is credited at the Net Metered credit values if there is more generation than on-site usage. For projects less than 5 MWs, the Company is the owner of the generation asset. Payments to the Net Metered customers and sales to ISO-NE are based on actual meter reads.

Payments to Net Metered customers with Eligible Net Metering Systems below 25 kW will be based on actual meter reads from a retail non-interval meter. As there is no hourly information available from a non-interval meter, there are no generator assets at the ISO-NE and, therefore, no sales to ISO-NE.

Prepared by or under the supervision of: Adam S. Crary

Record Request No. 5, page 2

Schedule ASC-16, Page 1 of 2

Page 1 of Schedule ASC-16 presents the net metering reconciliation and calculation of the net metering charge of the period ending December 31, 2015.

Column (a), Total Renewable Generation Credit, represents the renewable net metering credits that the Company paid to Eligible Net Metering Systems (Host Customers) for up to one hundred percent (100%) of the Host Customers' usage at the Eligible Net Metering System sites over the applicable billing period. The Renewable Net Metering Credit is equal to the total kWh of electricity generated and consumed on-site during the billing period multiplied by the sum of the:

1) SOS kWh charge for the rate class applicable to the net metering customer;
2) Distribution kWh charge;
3) Transmission kWh charge; and
4) Transition kWh charge.

For kWh generation between one hundred percent (100%) and one hundred twenty-five percent (125%) of the Host Customer's on-site usage, the Company pays the SOS rate applicable to the Host Customer for all kWh generated.

Column (b), Energy Sales to ISO-NE for Net-Metered Customers, represents the payments that the Company received from ISO-NE for energy generated by eligible net metering customers sold to ISO-NE.

Column (c), Qualifying Facilities Power Purchase Recoverable Costs, represent net costs that the Company incurred pursuant to the Qualifying Facility Power Purchase Rate, RIPUC No. 2098. For facilities meeting the definition of renewable energy resources as defined in RIGL Section 39-26-5, the Company pays the SOS rate applicable to that customer for each kWh generated in excess of the facility's requirements. The Company also receives payments from ISO-NE for energy generated by renewable Qualifying facilities. Column (c) represents the difference between the payments made to Qualifying Facilities with renewable generation at the SOS rate and the payments received from ISO-NE for market energy sold.

Finally, column (e), Ending Over (Under) Recovery Balance, is the sum of Columns (a) though (d).

Prepared by or under the supervision of: Adam S. Crary

Record Request No. 6

Request:

Looking at ASC-16 and ASC-18, please explain how the calculation of the net metering charge and the LTCRER interact, if at all. Please also provide an explanation of each factor that makes up each component of the columns on ASC-18, page 1, page 3 and page 4. For pages 3 and 4, please indicate which statutory program is included in each of the revenues and expenses.

Response:

The Net Metering Charge and LTCRER Factor are combined on customers' bills as the Renewable Energy Distribution Charge. These charges are combined for billing purposes only and do not otherwise interact with one another.

Pursuant to LTC Recovery Provision, RIPUC No. 2127, the Company is allowed to recover the costs incurred in accordance with the provisions of RIGL Chapter 39-26.1, Long-Term Contracting Standard for Renewable Energy, and RIGL Chapter 39-26.2, Distributed Generation Standard Contracts. Pursuant to Rhode Island law, the Company is required to enter into contracts with eligible renewable energy resources at fixed prices for the purchase of energy, capacity, and Renewable Energy Certificates (RECs) (collectively, the Contract Products). The Company will sell the energy purchased through the contracts into the ISO-NE energy market and will use the RECs to satisfy the Company's REC obligation associated with SOS. The difference between the cost incurred under each contract, equal to the fixed contract price multiplied by the generation of the facility, and the proceeds that the Company receives for the sale of the Contract Products, is referred to as the above market contract cost. Per RIGL § 39-26.1-5(f), the above market contract costs are to be recovered from all retail delivery service customers through a uniform per kWh factor. In addition, the Company is authorized pursuant to RIGL § 39-26.1-4 to recover 2.75 percent of the total payments made under each contract as remuneration. Finally, certain administrative and other costs authorized through various sections of the statutes will be tracked and recovered annually.

On an annual basis, the Company is required to reconcile the revenue billed through the LTC Recovery Factor and the expenses incurred pursuant to the LTC Recovery Provision. Schedule ASC-18 presents the Company's Reconciliation and LTCRER Factor Calculation. Page 1 contains a summary of revenue and expenses while pages 3 and 4 contain detailed revenue and expense information, respectively.

Page 1, Column (b) shows the revenue billed each month through the LTC Recovery Factor during 2015 totaling $3,023,550. Column (c) shows the monthly expense totaling $11.6 million for the twelve months ending December 31, 2015. Column (d) includes an adjustment of

($135,484), which is the ending balance of the under- recovery incurred during 2013 and recovered from customers during the period ending March 31, 2015. Column (e) shows the over- or under-recovery of expense for each month. Column (f) shows the cumulative over- or under-recovery as well as the ending under-recovery balance of $8.7 million.

Page 3 contains the derivation of the LTC Recovery Factor revenue billed during the reconciliation period. As discussed above, for billing purposes, the LTC Recovery Factor and the Net Metering Charge are combined and shown on customers' bills as the Renewable Energy Distribution Charge. Column (a) on Page 3 shows the monthly revenue billed through the Renewable Energy Distribution Charge. The LTC Recovery Factor revenue reflected in the LTC reconciliation is the result of disaggregating the revenue billed through the Renewable Energy Distribution Charge. The first step is to remove the portion of revenue related to the Net Metering Charge included in the Renewable Energy Distribution Charge revenue, which is shown in Column (b). The LTC Recovery Factor revenue is shown in Column (c) and is the difference between the total Renewable Energy Distribution Charge revenue shown in Column (a) and the Net Metering Charge revenue shown in Column (b). Column (d) represents the revenue associated with the prior year's under-recovery. The revenue supporting the uncollectible expense allowance is shown in Column (f). The remaining LTC Recovery Factor revenue shown in Column (g) represents the base revenue available to offset LTC expenses incurred during the reconciliation period.

Page 4 shows a summary of monthly expenses associated with the Company's long term and distributed generation standard contracts, as described above. The total contract cost shown in Column (a) less capacity revenue in Column (b) results in net contract payments shown in Column (c) for the twelve-month period. The Company sells the energy generated by each renewable resource into the ISO-NE energy market and receives a payment from ISO-NE equal to the hourly generation of each resource multiplied by the hourly locational marginal price. In addition, as approved in the Company's 2013 Renewable Energy Standard Plan in Docket No. 4315, the Company utilizes the RECs produced by each resource to satisfy its RES obligation for SOS. The Company determines the market value of the RECs on a quarterly basis as they are delivered. RECs are delivered to the Company through the NEPOOL GIS on a quarterly basis, and the Company assesses their value at delivery every three months by calculating the average of the available market prices two weeks before and after the delivery. Market price information includes recent REC solicitation results, broker information, and published indices in accordance with the methodology approved in the RES Plan. These Contract Products, consisting of the energy market proceeds resulting from the sale of the purchased energy into the ISO-NE energy market and the value of the RECs, are shown in Columns (d) and (e), respectively. The above market cost in Column (f) is the net contract cost less the value received for the Contract Products. Column (g) shows Other Charges and Credits, representing forfeited performance guarantee deposits retained from resources that did not complete required contract milestones. Column (h) shows the contract remuneration is calculated by multiplying Contract Cost Less Capacity Revenue in Column (c) by the remuneration rate of 2.75%, and Column (i) shows the total costs to be recovered for the year.

Prepared by or under the supervision of: Adam S. Crary

Record Request No. 7

Request:

Please provide the status of the Champlain Wind PPA.

Response:

On December 30, 2015, Champlain Wind provided notice to the Company that they have elected to extend the critical milestone dates under the PPA, which is attached as Attachment RR-7a. Champlain Wind also provided a progress report dated December 31, 2015, which is attached as Attachment RR-7b. As indicated in that progress report, the Maine Supreme Judicial Court rejected the appeal of the Department of Environmental Protection denial of the permit for the project and Champlain Wind is evaluating next steps.

CHAMPLAIN WIND, LLC

PROGRESS REPORT

For the Quarter Ending: 12/31/2015

Status of construction and significant construction milestones achieved during the quarter:

Project construction will not commence until required permits and financing are secured.

Status of permitting and significant Permits obtained during the quarter:

In December 2015, the Maine Supreme Judicial Court rejected the appeal of the DEP denial of the permit for Bowers Wind. Champlain Wind, LLC is evaluating next steps. System Impact Study agreement for the project has been executed with ISO-NE.

Status of Financing for Facility:

Project financing has not commenced.

Events during quarter expected to result in delays in Commercial Operation Date:

The Court decision on the project permit has created high uncertainty for the project schedule.

Critical Milestones not yet achieved and projected date for achievement:

3.1(a)(i)	TBD
3.1(a)(ii)	12/31/2016
3.1(a)(iii)	12/31/2016
3.1(a)(iv)	2/28/2017
3.1(a)(v)	3/31/2017
3.1(a)(vi)	3/31/2018

Current projection for Commercial Operation Date:

Q1 2018

SunEdison®

VIA EMAIL to Corinne.DiDomenico@nationalgrid.com

December 30, 2015

Corinne DiDomenico
Manager, Environmental Transactions
Energy Procurement
National Grid
100 E. Old Country Road
Hicksville, NY 11801-4218

Re: Power Purchase Agreement dated as of August 2, 2013 by and between The Narragansett Electric Company, d/b/a National Grid and Champlain Wind, LLC (the "Agreement")

Dear Ms. Abrams,

Pursuant to Section 3.1(c) of the referenced Agreement, Champlain Wind, LLC hereby elects to extend the date of each Critical Milestone listed in Section 3.1(a)(i)-(vi) by one year.

We will continue to update National Grid with respect to the achievement of Critical Milestones in the accordance with the Agreement. Please feel free to contact me with any questions.

Sincerely,

CHAMPLAIN WIND, LLC
BY: Maine Wind Holdings, LLC, its Member

Aaron MacQueen
Assistant Secretary

cc: Jennifer Brooks Hutchinson, Esq. *via email Jennifer.Hutchinson@nationalgrid.com*